"A NEW MODEL FOR FRACTURE GRADIENT"

by

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This paper is to be presented at the 5th Formation Evaluation Symposium of the Canadian Well Logging Society in Calgary, May 5 - 7, 1975. Discussion of this paper is invited. Such discussion may be presented at the Symposium and will be considered for publication if filed in writing with the Technical Program Chairman prior to the conclusion of the Symposium.

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ABSTRACT

For the past eighteen years fracture gradient has been thought to be some function of overburden stress, horizontal stress and internal fluid pressure. Each author that has published in the intervening years has refined this idea. This paper derives such a model but then uses the same data to turn the entire relationship around to derive and support a new model with the following attributes:

1. Fracture gradient is equal to the least stress field in the earth.
2. Fracture gradient is independent of the fluid pressure gradient. It depends only on the earth's stress field.
3. Fluid pressure gradient is dependent on fracture gradient. If the fluid pressure gradient equals the fracture gradient, the earth fractures and the fluid is released to permeable beds.
4. Most abnormal fluid pressure systems may be pressured to the fracture gradient at their structurally highest point.

INTRODUCTION

Since the publication of Hubbert and Willis[11] on hydraulic fracturing in 1957, most authors have held that fracture gradient is a function of overburden stress, horizontal stress and internal fluid pressure, although the exact relationship has remained in dispute. A recent article, however, by MacPherson and Berry[12] states that in calculating fracture gradient from sonic and density logs, they found no evidence that the formation fluid pressure gradient effects the fracture gradient. This strikes a sympathetic point with this author and the result is this paper.

The data gathering and the original curve fitting for this project were done in 1967; but since a number of papers were published that year on fracture gradient, one more paper giving essentially the same results did not seem warranted. The original work is included; however, the purpose of this paper is to show that the same data that was used to relate fracture gradient to pressure gradient can be used to turn the entire equation around and relate pressure gradient to fracture gradient as the independent variable. This solution suggests that fracture gradient is dependent only on minimum regional stress. A body of theory has been derived that indicates that this solution is possible.

SAMPLING PROCEDURE

The sample for this project included most of the lost returns encountered by Exxon while drilling in South Louisiana and the Louisiana Offshore from 1964 to mid-1967. A total of sixty-six cases were used which is considered to be a statistically satisfactory sample. The geological section sampled ranged from Lower Miocene to Recent in age with the bulk of the data being Upper Miocene.

A basic assumption was made in gathering data that the point of fracture in each well was at the highest exposed depth and the lowest exposed formation fluid pressure below the deepest casing set in the well at the time of lost returns. Since no cases were found in this sample where the formation fluid pressure decreased with depth, the fracture point was picked in all cases as the first exposed point below casing.

The fracture gradient points were taken from the weights of the muds in use at the time that mud returns were lost while drilling. No attempt was made to correct for bit jet pressure, circulating friction or drill pipe surging. No distinction could be made between formation breakdown pressure and fracture maintenance pressure. The formation breakdown in all cases appears to have been at the fracture maintenance pressure. This can happen if the hole is far enough out of round or fractures are already present.[18] The data values are considerably below those normally obtained by deliberate fracturing.

The formation fluid pressure gradient was obtained for each point of lost returns. Most fluid pressure points were calculated using resistivity plots for the sample wells and pressure charts derived by this author for the area of study. (Unpublished) A few gradients were taken from mud weights when reliable mud cuts or actual kicks occurred in the sample wells.

OVERALL VIEW OF PROJECT DATA

The best overall view of the project data can be obtained by looking at Exhibit I. In this exhibit all of the fracture gradient data has been plotted as depth of fracture vs. fracture gradient along with the overburden gradient. The overburden gradient as here defined is the average overburden density from any depth point back to the surface. This overburden gradient line was calculated from a density vs. depth plot of the younger Gulf Basin section which was obtained from my associates in the Gravity Section. These density data originated from downhole gravity meter surveys and core density measurements combined with published data. The fracture gradient is roughly 2/3 of the overburden gradient near the surface and approaches the overburden gradient below 14,000 feet. In no case did the fracture gradient exceed the overburden gradient line.

SOLUTION TO NORMAL FLUID PRESSURE GRADIENT DATA

This problem was first tackled with curve fitting techniques with little regard for theory. The fracture problem was simplified by sorting out all of the normal formation fluid pressure gradient points and plotting these by themselves, thus excluding any effect from changing fluid pressure gradient. These are shown on Exhibit II. The points to 6,000 feet were taken from lost returns below surface casing whereas the points below 12,000 feet were taken from lost returns below protection casing. No data was available for the interval between the two groups of data since wells in the sample did not have casing set between 6,000 and 12,000 feet. The least squares line shown on Exhibit II appears to be the best fit of these data and shows a linear increase of fracture gradient with depth. The formula for this line is as follows:

Fracture Gradient* = 11.082+ .00043 (depth)
*lb./gal.
Correlation Coefficient = .9369
Standard Error of Estimate = .8563 lb/gal.

SOLUTION TO THE ABNORMAL FLUID PRESSURE GRADIENT DATA

The relationship between formation fluid pressure gradient and fracture gradient is not linear as can be seen on Exhibit III where the formation fluid pressure gradient was plotted versus fracture gradient. Note that the normal pressure points (9 lb./gal.) scatter up the entire left side of the plot. These are the points that were used to plot fracture gradient versus depth in Exhibit II. The scatter is due to the increase of fracture gradient with depth. Above a 11.5 lb./gal. formation fluid pressure gradient, pressure gradient versus fracture gradient shows an excellent linear correlation. For this reason, the data was divided for linear regression at the 11 lb./gal. point which also happens to be at 10,000 feet on depth. A multiple linear regression solution was accepted containing formation fluid pressure and depth as the independent variables. The formula for this solution is as follows:

Fracture Gradient*= 13.28012+.0001 (depth)
+ .22553 x (formation
fluid pressure gradient*)
*lb./gal.
Correlation Coefficient = .7879
Standard Error of Estimate = .4594*

This formula is shown graphed on both Exhibit III and Exhibit IV along with the project data. Exhibit III shows formation

fluid pressure gradient versus fracture gradient with individual lines for depth. Exhibit IV shows fracture gradient versus depth with individual lines for pressure gradient. The pressure gradient lines on Exhibit IV very nearly parallel the overburden gradient. The solution lines were drawn only over the area where data exists.

The normal and abnormal solution were combined on Exhibit V for field use. This solution has been in use in south Louisiana since 1967.

FITTING DATA TO FRACTURE THEORY

The data was also used to derive Matthew's and Kelly's K Coefficient[13] defined as:

$$K = \frac{\text{Fracture Gradient} - \text{Fluid Pressure Gradient}}{(\text{Overburden Gradient} - \text{Fluid Pressure Gradient})}$$

The overburden gradient was held constant at 19.2 lb./gal. (1.0 psi/ft.) to simplify calculations.

Linear regression was run on K versus depth and K versus depth of normal matrix stress. The K versus depth of normal matrix stress as suggested by Matthews and Kelly[13] was not very satisfactory. (See Exhibit VI.) A better solution was simply K versus depth shown on Exhibit VII. This solution unifies both the normal pressure and abnormal pressure data in a satisfactory way. The formula is as follows:

$$K = .23375 + .00004 \text{ (depth)}$$

Correlation Coefficient = .8651
Standard Error of Estimate = .1018

In the problem data, the fracture gradient exists between the formation pressure gradient and the overburden gradient. The solution for K indicates that its position between these two depends on depth.

The formula for calculating fracture gradient becomes:

$$\text{Fracture Gradient}^* = K(19.2 - \text{Fluid Pressure Gradient}) + \text{Fluid Pressure Gradient}^*$$

*lb./gal.

This equation is of the form of most of those published. The empirically derived K could be any combination of the stress relationships in the published formulas. The formula form is particularly close to that of Hubbard and Willis[11]. The formula graphs out for use as shown on Exhibit VIII. Only the range covered by data is shown in the solution. An extension of these lines through the area devoid of data could result in curved lines that tend to parallel the overburden gradient line.

DESCRIPTION OF A NEW MODEL

The problem appears to be solved along the lines already published, but is this solution beyond any doubt? Let's use this same data to evaluate a different model.

NEW MODEL

1. In a relaxed basin such as the Northern Gulf of Mexico the fracture maintenance gradient is equal to the least horizontal stress.

2. Fracture gradient is independent of fluid pressure gradient. It depends only on the horizontal stress pattern.

3. Abnormal fluid pressure has been shown to develop when natural channels do not exist to exhaust fluids from compacting sediments. The blockage can be due to faulting, discontinuous sands, etc. Once the blockage exists, the fluid pressure gradient buildup is dependent on fracture gradient. If the fluid pressure gradient exceeds the fracture gradient, the earth fractures and the fluid exhausts upward through these fractures to permeable beds. This continues until the fluid pressure drops below the fracture gradient, allowing a gradual fluid evacuation from abnormal pressure formations.

4. Most active abnormal fluid pressure systems may be pressured to the fracture gradient at their structurally highest point.

MECHANISM OF FRACTURING

This model could not be taken seriously unless a mechanism could be illustrated that would allow fluid pressures as encountered to become greater than fracture pressures if, in fact, fracture gradient is independent of fluid pressure gradient. The fluid pressures in the project sample should in some logical way be able to exceed the fracture pressures in the sample. A mechanism was described by Dickinson[4] in 1953 that could create this situation.

The most dramatic example of this mechanism occurs in abnormal pressure drilling when an overpressure is encountered and the rams are closed. The overpressure is transmitted to all points in the fluid column. If the surface casing is short, the resulting lack of overburden can cause a fluid pressure gradient at the bottom of the casing that is quite high. The same situation in a less severe form occurs naturally in the earth. Exhibit IX shows a hypothetical case where well 1 has tested 15,000 psi at 17,000 feet which indicates a fluid pressure gradient of 17 lb./gal. or .885 psi/ft. If this same zone is drilled 2,000 feet higher in the same pressure system, as shown by well 2, the pressure should

be 15,000 psi minus the weight of the column of water (15,000 - 930 = 14,078 psi). The fluid pressure gradient with the reduced overburden is 18 lb./gal. or .94 psi/ft. Exhibits X, XI and XII show the graphical solution to this problem for permeable zones that have tests made at 5,000, 10,000 and 15,000 feet.

Chart XIII sums up this entire line of thought by presenting the vertical distance from the pressure test point to the fracture point for various abnormal fluid pressures and depths. The chart was constructed by taking fracture gradients from Exhibit VIII for 5,000, 10,000 and 15,000 feet and for 12, 15 and 18 lb./gal. fluid pressure gradients and tracing these data through Exhibits X, XI and XII to find the height above a measured fluid pressure point that a bed would fracture. Some iterations between the charts are necessary to get the answer since fracture gradient changes with depth as well as fluid pressure gradient on Exhibit VIII.

Beds that contain abnormal fluid pressure are generally deeper water deposits that are likely to be deposited on continental slopes. Permeable beds with an initial updip vertical distance component of 1,000 feet are common and 2,000 feet is well in the range of possibility. Later subsidence increases this dip. The lower values developed on Exhibit XIII appear to be in the range of probability. At 15,000 feet with an 18 lb./gal. fluid pressure gradient, a bed that extends for 1,400 feet vertically will fracture. This is the usual pressure and vertical bed extent for this depth. The mechanism for self-induced pressure fracturing of the earth exists. If fracture gradient does not increase with pressure gradient but is dependent only on the earth's stress pattern, this mechanism is probably active. Most abnormal pressure beds can be traced updip to a point where they would fracture under the conditions of this model.

FORMULA FOR NEW MODEL

The project data was used to derive formulas "proving" that fracture gradient is a function of pressure gradient. It is just as easy to derive formulas to "prove" the opposite. The user of the data has decided his solution ahead of his mathematical manipulations when he picks his dependent variable. To illustrate this idea, linear regression was run on the forty-one abnormal pressure points using pressure gradient as the dependent variable. The resulting solution is shown on Exhibit XIV.

Pressure Gradient*= -20.2 + 1.93 x fracture gradient*

*lb./gal.

Correlation Coefficient = .745
Standard Error of Estimate = 1.27 lb./gal.

Rerunning these data and allowing the depth to enter the formula yields the following formula which is shown on Exhibit XV.

Pressure Gradient*= -18.2 +.0001 x Depth + 1.736 x fracture gradient

*lb./gal.

Correlation Coefficient = .751
Standard Error of Estimate = 1.27 lb./gal.

The depth function has not increased the correlation enough to be of use so the preferred formula is the first which simply relates pressure gradient to fracture gradient. The correlation coefficient for this solution is almost as good as for the one that related fracture gradient to pressure gradient (.745 versus .788).

RE-INTERPRETING EXHIBITS USING THE NEW MODEL

Many of the exhibits derived from the project data to support the traditional model can be re-interpreted to support the new model. For instance, in support of the idea that the fracture maintenance pressure is equal to the least horizontal stress, Exhibit II can be thought of as a plot of minimum horizontal stress versus depth. The chart then shows that the minimum horizontal stress increases and approaches the overburden stress with depth in the Gulf Coast Basin. For another presentation of this same idea, the solution shown on Exhibit VIII was divided by the overburden gradient to produce Exhibit XVI. This graph shows the minimum horizontal stress as a percent of overburden stress plotted as a function of depth and fluid pressure gradient. The minimum horizontal stress is near 70% of overburden stress near the surface and approaches overburden stress at 19,000 feet. The various curves for different pressures could simply represent minimum horizontal stresses that are higher in some parts of the study area due to regional stress patterns. These areas are capable of holding higher fluid pressures.

Additional insight may be gained from the K coefficient solution shown on Exhibit VII. This solution may simply be the result of sampling a number of beds at various positions relative to their updip fracture point. A statistical average of pressure would always be several lb./gal. below a statistical average of fracture gradients for any given depth with the range narrowing as the overburden gradient is approached.

THE NEW MODEL AND REGIONAL GEOLOGY

The regional geology of the Gulf Coast tends to support a stress pattern such as the interpretation of Exhibit XVI already given. In this relaxed basin the sediments are compacting in an only partly confined

situation since they are moving toward the center of the basin on a salt and/or abnormal pressure shale substratum. This movement is aided by regional down-to-the-basin faulting that often becomes bedding plane faulting. The least horizontal stress, which is perpendicular to the faulting, does not approach the overburden stress until the basinward movement is confined by depth of burial. The deeper beds are below the total depth of the Gulf of Mexico and have no open space in which to move. The stress pattern varies over the area depending upon how easily the sediments can move toward the center of the basin.

A second line of geological evidence suggests that fracture gradient is independent of fluid pressure gradient. Most wells that drill abnormal pressure have a maximum resistivity, density and velocity zone immediately above abnormal pressure, usually 500 to 1,000 feet thick. There is an excellent possibility that the minimum horizontal stress field increases quite rapidly downward through this section creating the confining pressure that is responsible for the increased compaction which is apparent on the logs. Exhibit XVI indicates that abnormal pressure does not occur until minimum horizontal stress reaches 90% of overburden stress. Most likely this stress situation is satisfied in the maximum compaction zone but abnormal pressures do not occur in this zone because natural permeable avenues are open for the expulsion of water squeezed out of the shales. Below this compaction zone, formations occur that have no natural avenues for fluid movement and the fluid pressure buildup is the result. This appears to be the situation that MacPherson and Berry[12] were dealing with when they calculated fracture gradient from sonic and density logs and found no relationship between formation fluid pressure gradient and fracture gradient.

The best proof of the model may lie in the mounting evidence derived from oil maturation studies that indicate that many Gulf Coast hydrocarbons are much too mature for their depth of entrapment. Migration from considerable depth is needed either horizontally or vertically to satisfy the known conditions. In most cases, a vertical migration by fracturing along fault zones is the simpler solution.

SUMMARY AND CONCLUSIONS

Three models have been presented describing fracture gradient based on the same data, the last one of which is directly opposed to the first two. The author is suggesting the possibility that the published solutions to the fracture gradient problem have been over-refined each becoming more complicated by building on the previous ones. Another solution to the problem is available that interprets the data differently and incorporates various aspects of the regional geology. The purpose of this paper is to open this topic up to discussion again and to turn new studies into new directions. The old solutions have served us well in fracture prediction for many years, but are they really the final answers to this problem?

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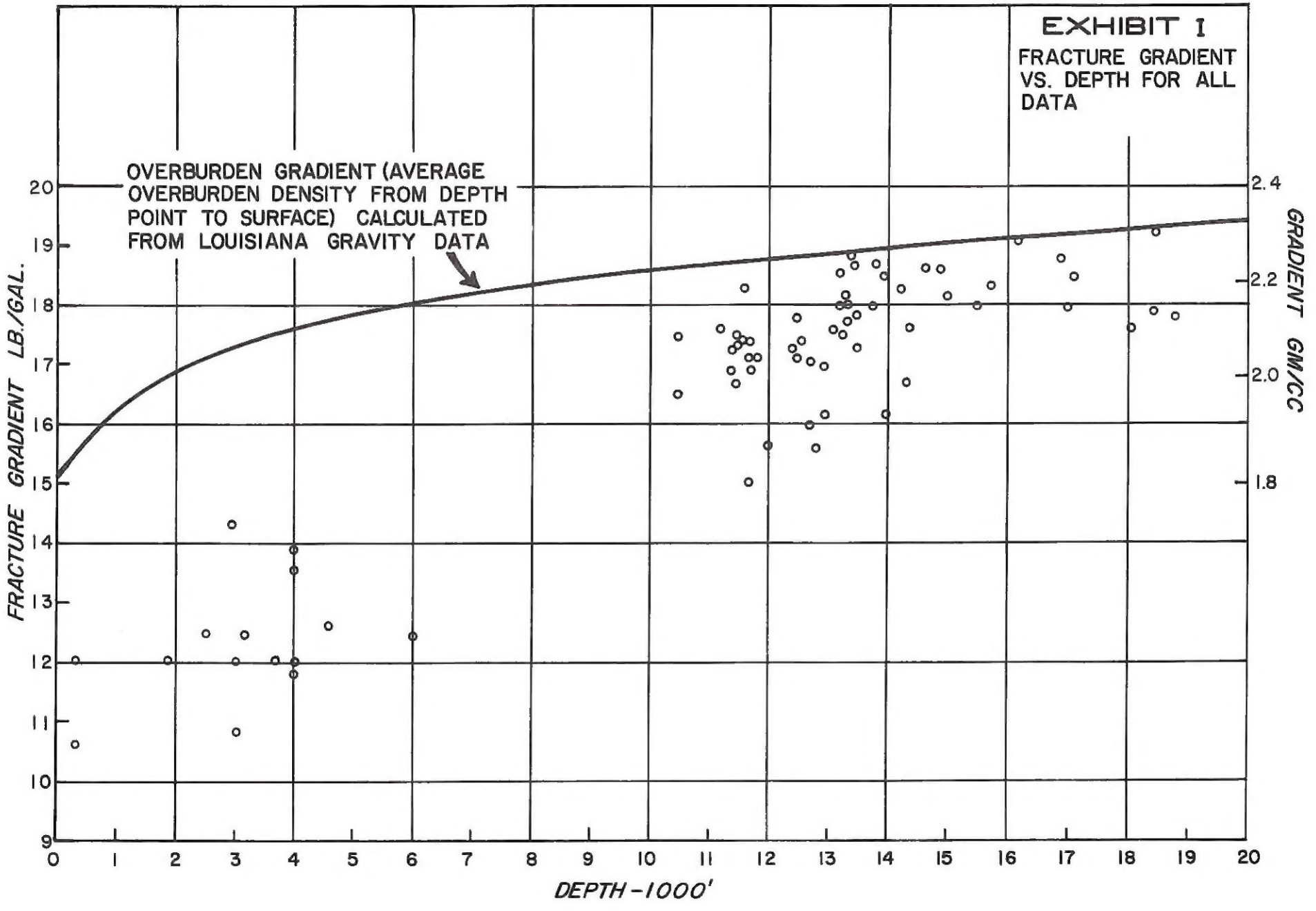
EXHIBIT I
FRACTURE GRADIENT VS. DEPTH FOR ALL DATA
OVERBURDEN GRADIENT (AVERAGE OVERBURDEN DENSITY FROM DEPTH POINT TO SURFACE) CALCULATED FROM LOUISIANA GRAVITY DATA
FRACTURE GRADIENT LB./GAL.
GRADIENT GM/CC
DEPTH - 1000'
20
19
18
17
16
15
14
13
12
11
10
9
2.4
2.2
2.0
1.8
0
1
2
3
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12
13
14
15
16
17
18
19
20

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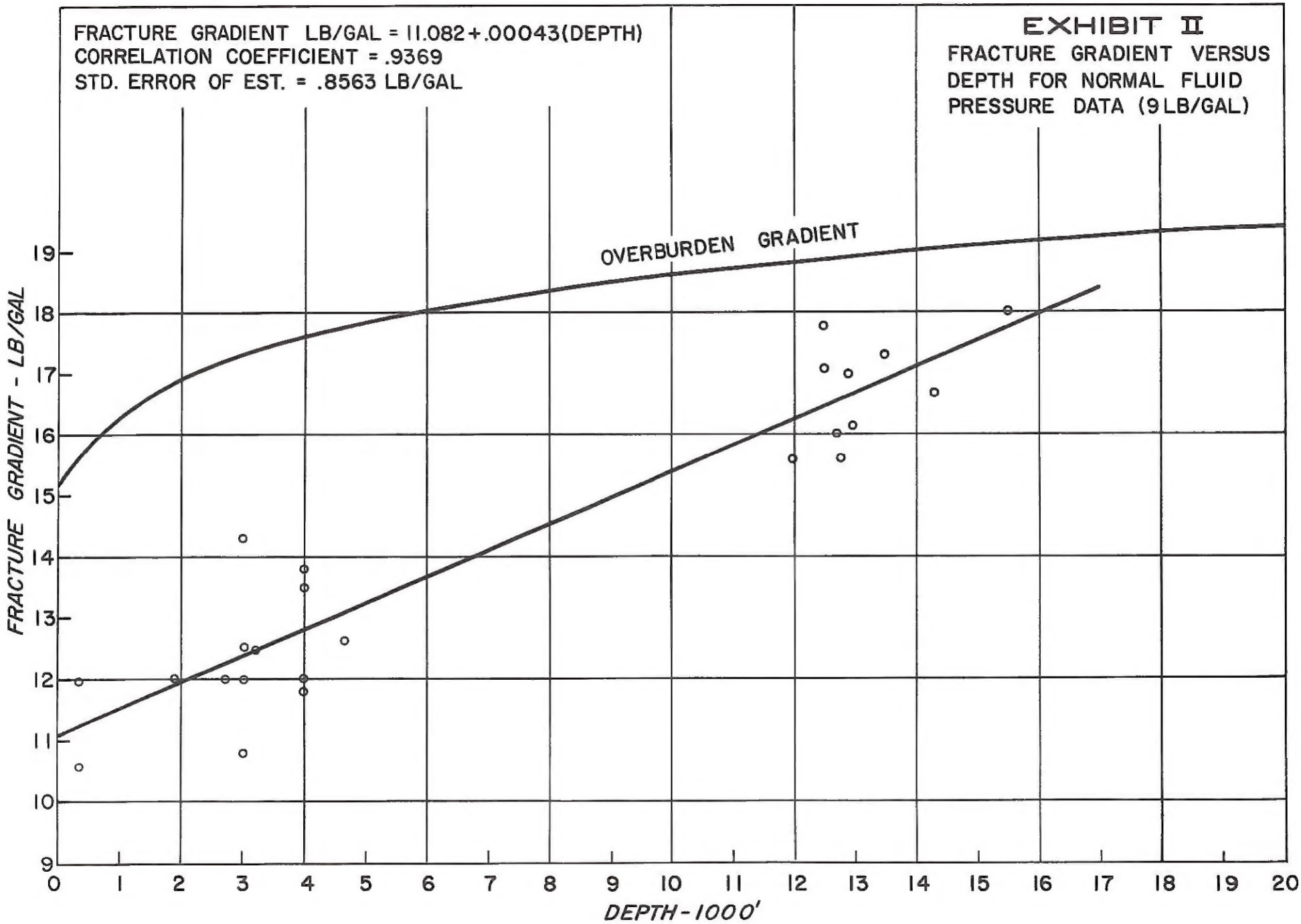
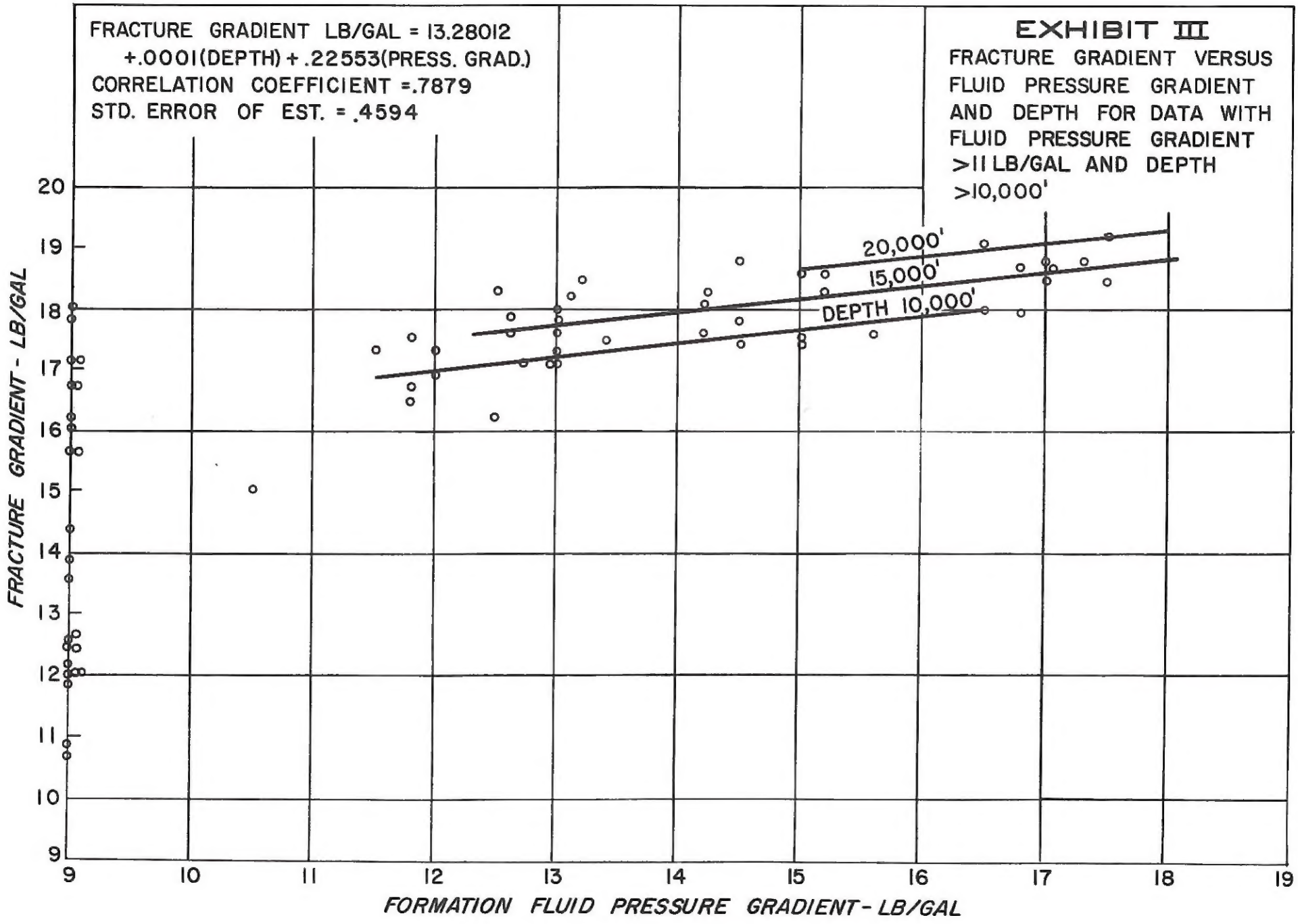

FRACTURE GRADIENT LB/GAL = 11.082+.00043(DEPTH)
CORRELATION COEFFICIENT = .9369
STD. ERROR OF EST. = .8563 LB/GAL
EXHIBIT II
FRACTURE GRADIENT VERSUS DEPTH FOR NORMAL FLUID PRESSURE DATA (9 LB/GAL)
OVERBURDEN GRADIENT
FRACTURE GRADIENT - LB/GAL
DEPTH - 1000'
9
10
11
12
13
14
15
16
17
18
19
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20


FRACTURE GRADIENT LB/GAL = 13.28012
+.0001(DEPTH) + .22553(PRESS. GRAD.)
CORRELATION COEFFICIENT =.7879
STD. ERROR OF EST. = .4594
EXHIBIT III
FRACTURE GRADIENT VERSUS FLUID PRESSURE GRADIENT AND DEPTH FOR DATA WITH FLUID PRESSURE GRADIENT >11 LB/GAL AND DEPTH >10,000'
20,000'
15,000'
DEPTH 10,000'
FRACTURE GRADIENT - LB/GAL
FORMATION FLUID PRESSURE GRADIENT - LB/GAL
9
10
11
12
13
14
15
16
17
18
19
20

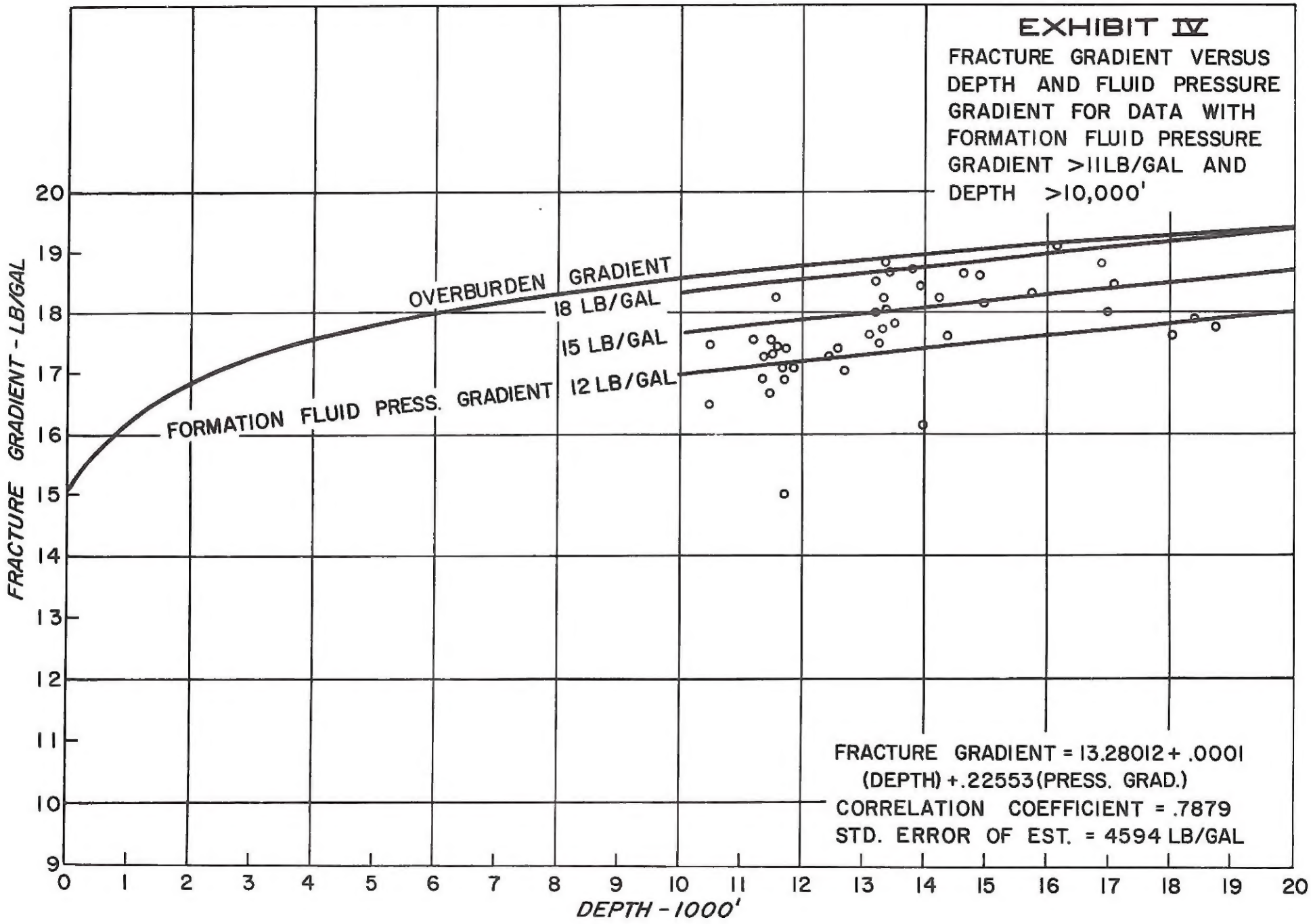


EXHIBIT IV
FRACTURE GRADIENT VERSUS DEPTH AND FLUID PRESSURE GRADIENT FOR DATA WITH FORMATION FLUID PRESSURE GRADIENT >11LB/GAL AND DEPTH >10,000'
OVERBURDEN GRADIENT
18 LB/GAL
15 LB/GAL
12 LB/GAL
FORMATION FLUID PRESS. GRADIENT
FRACTURE GRADIENT = 13.28012 + .0001 (DEPTH) + .22553 (PRESS. GRAD.)
CORRELATION COEFFICIENT = .7879
STD. ERROR OF EST. = 4594 LB/GAL
FRACTURE GRADIENT - LB/GAL
DEPTH - 1000'
9
10
11
12
13
14
15
16
17
18
19
20
0
1
2
3
4
5
6
7
8
9
10
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14
15
16
17
18
19
20

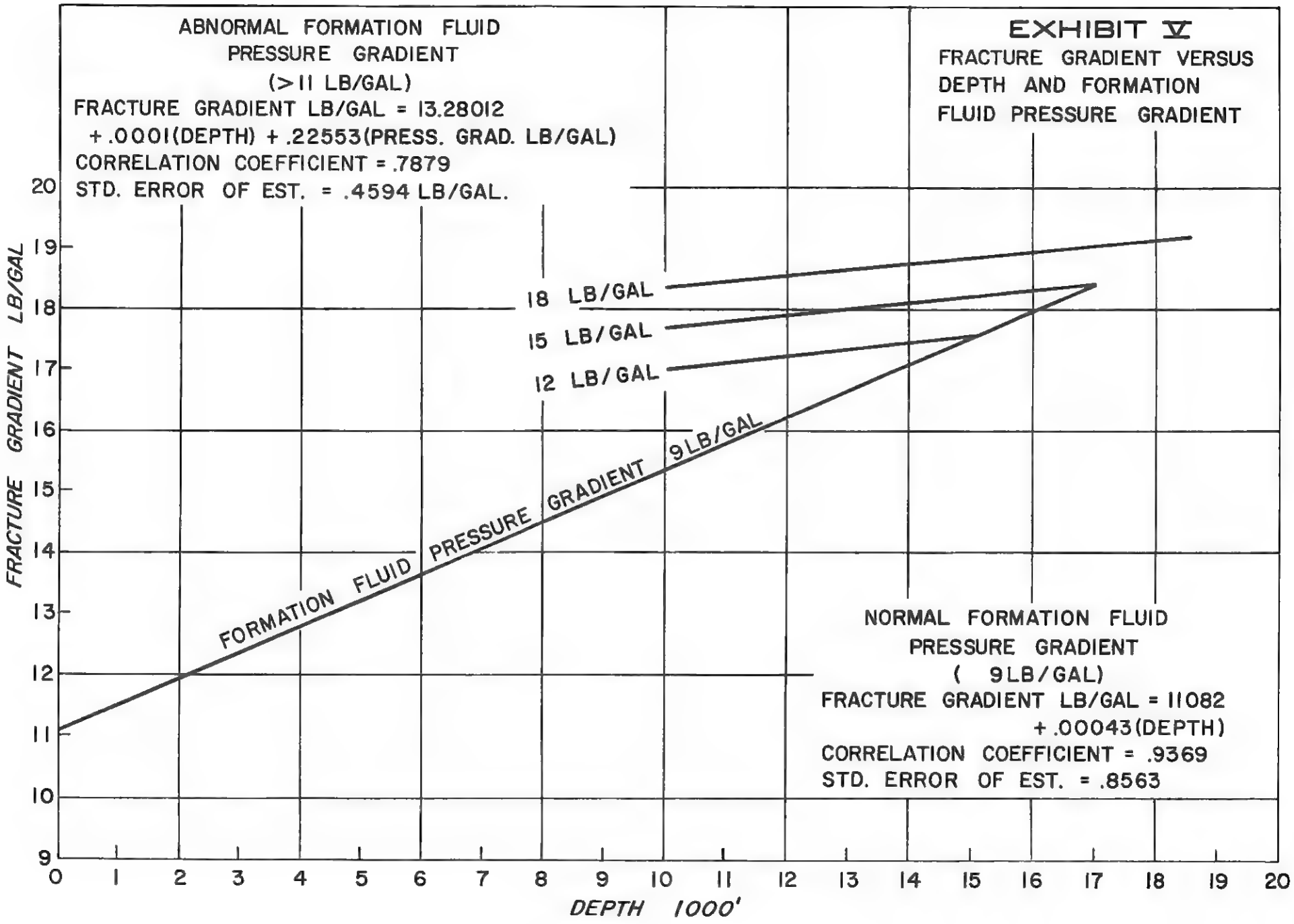
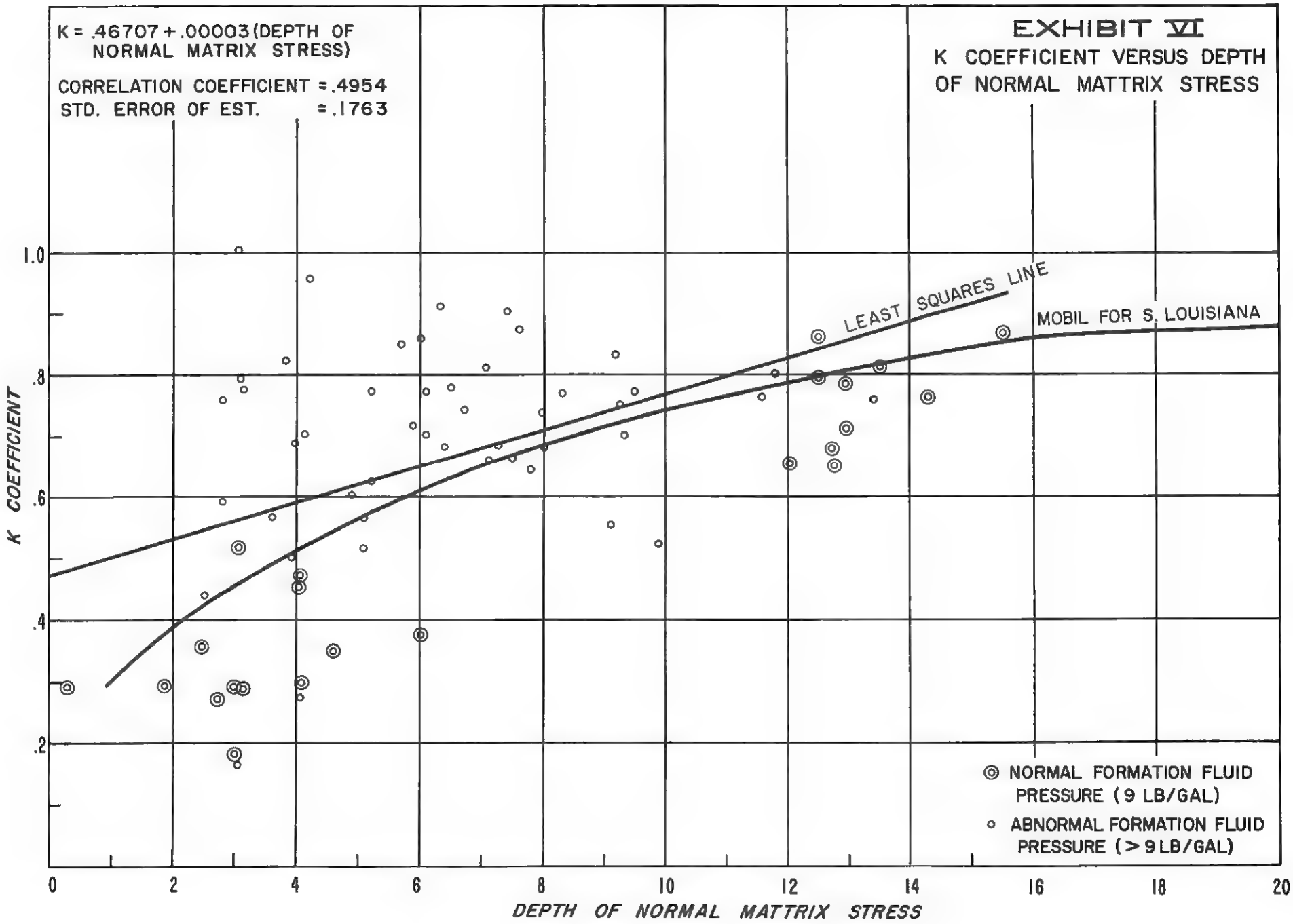
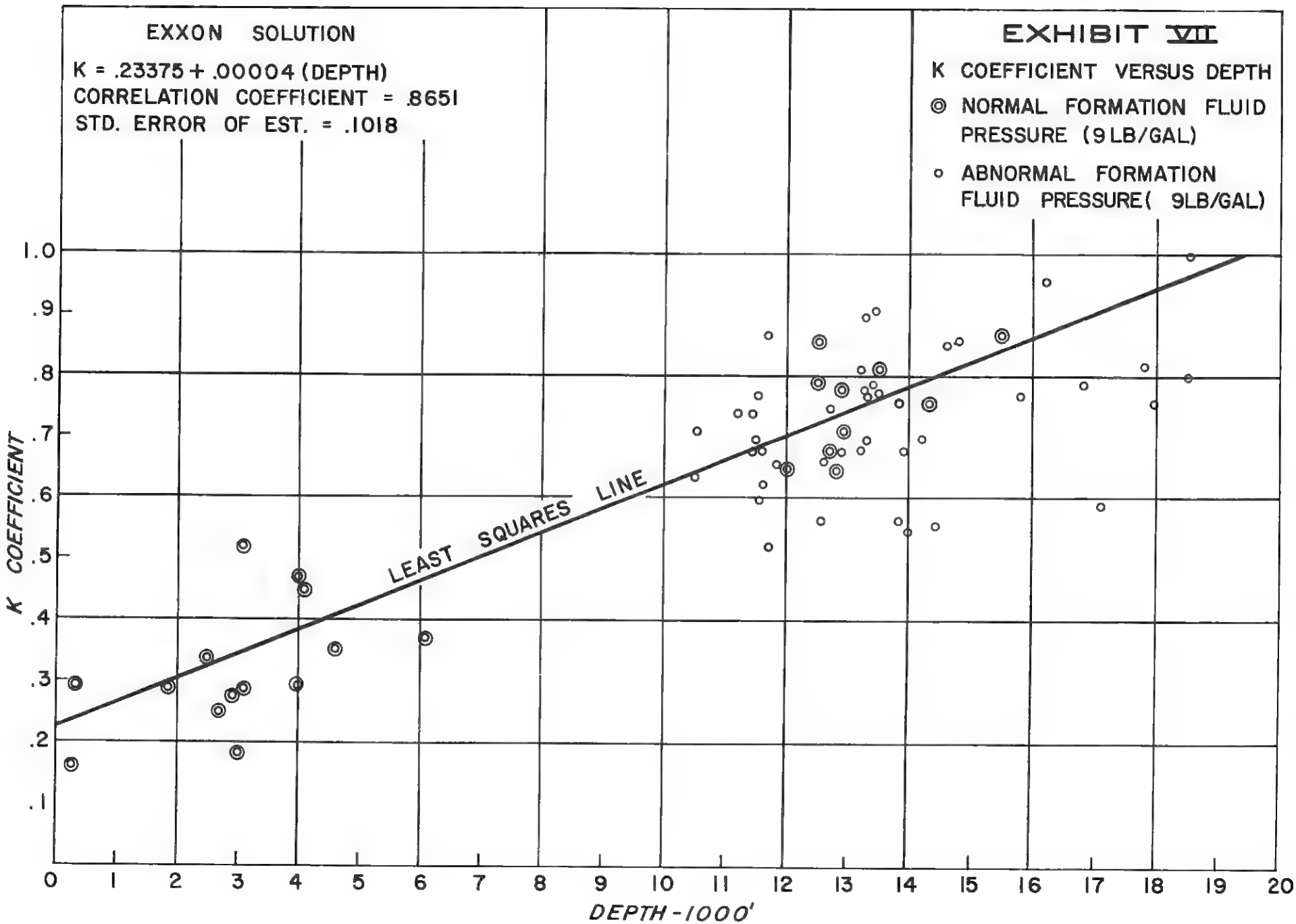


EXHIBIT V
FRACTURE GRADIENT VERSUS DEPTH AND FORMATION FLUID PRESSURE GRADIENT
ABNORMAL FORMATION FLUID PRESSURE GRADIENT (>11 LB/GAL)
FRACTURE GRADIENT LB/GAL = 13.28012 + .0001(DEPTH) + .22553(PRESS. GRAD. LB/GAL)
CORRELATION COEFFICIENT = .7879
STD. ERROR OF EST. = .4594 LB/GAL.
18 LB/GAL
15 LB/GAL
12 LB/GAL
FORMATION FLUID PRESSURE GRADIENT 9LB/GAL
NORMAL FORMATION FLUID PRESSURE GRADIENT (9LB/GAL)
FRACTURE GRADIENT LB/GAL = 11082 + .00043(DEPTH)
CORRELATION COEFFICIENT = .9369
STD. ERROR OF EST. = .8563
FRACTURE GRADIENT LB/GAL
DEPTH 1000'
9 10 11 12 13 14 15 16 17 18 19 20
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20


K = .46707 + .00003 (DEPTH OF NORMAL MATRIX STRESS)
CORRELATION COEFFICIENT = .4954
STD. ERROR OF EST. = .1763
EXHIBIT VI
K COEFFICIENT VERSUS DEPTH OF NORMAL MATTRIX STRESS
LEAST SQUARES LINE
MOBIL FOR S. LOUISIANA
NORMAL FORMATION FLUID PRESSURE (9 LB/GAL)
ABNORMAL FORMATION FLUID PRESSURE (> 9 LB/GAL)
K COEFFICIENT
1.0
.8
.6
.4
.2
0
2
4
6
8
10
12
14
16
18
20
DEPTH OF NORMAL MATTRIX STRESS


EXXON SOLUTION
K = .23375 + .00004 (DEPTH)
CORRELATION COEFFICIENT = .8651
STD. ERROR OF EST. = .1018
EXHIBIT VII
K COEFFICIENT VERSUS DEPTH
NORMAL FORMATION FLUID PRESSURE (9 LB/GAL)
ABNORMAL FORMATION FLUID PRESSURE(9LB/GAL)
LEAST SQUARES LINE
K COEFFICIENT
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
DEPTH - 1000'

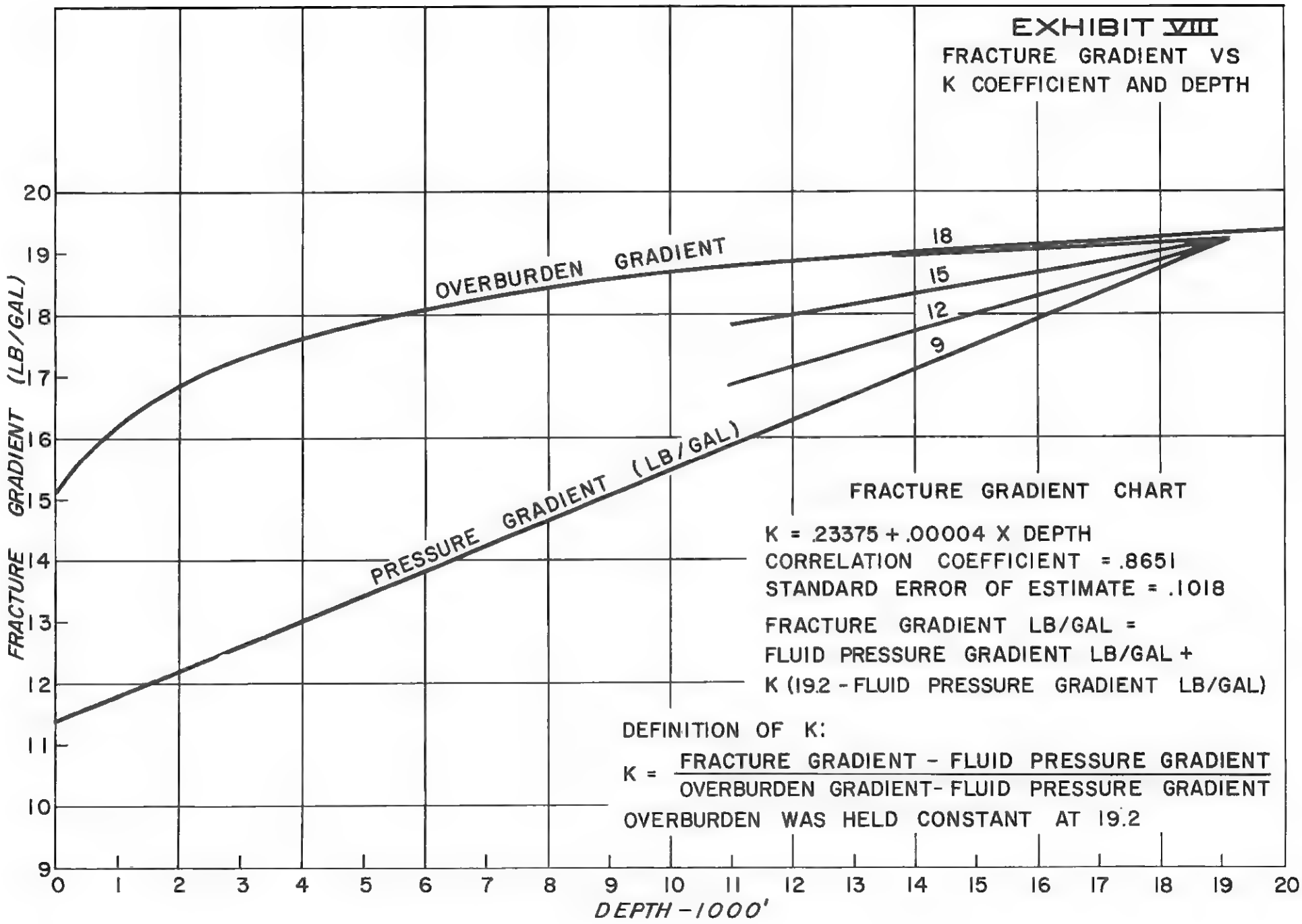
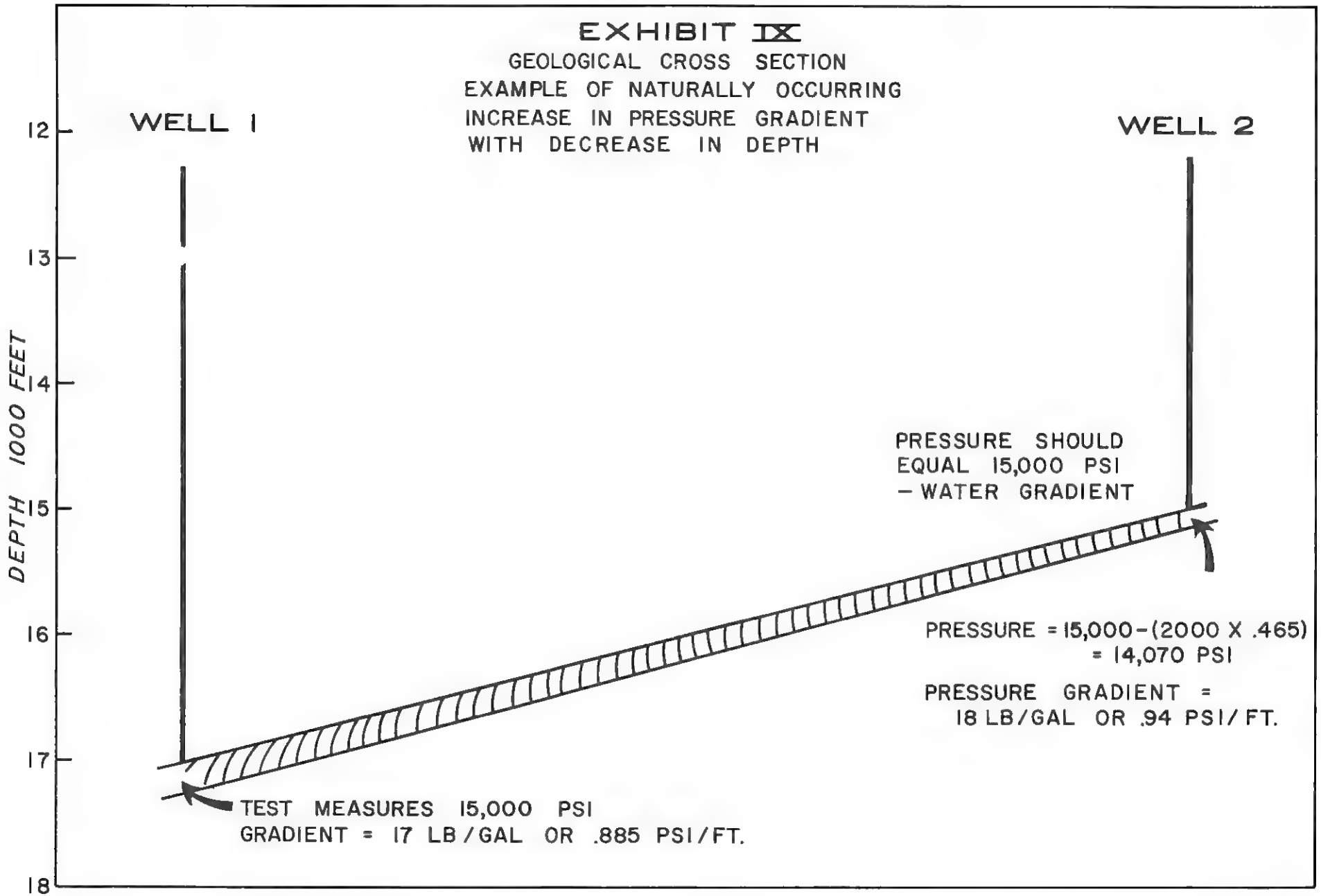


EXHIBIT VIII
FRACTURE GRADIENT VS
K COEFFICIENT AND DEPTH
OVERBURDEN GRADIENT
PRESSURE GRADIENT (LB/GAL)
18
15
12
9
FRACTURE GRADIENT CHART
K = .23375 + .00004 X DEPTH
CORRELATION COEFFICIENT = .8651
STANDARD ERROR OF ESTIMATE = .1018
FRACTURE GRADIENT LB/GAL =
FLUID PRESSURE GRADIENT LB/GAL +
K (19.2 - FLUID PRESSURE GRADIENT LB/GAL)
DEFINITION OF K:
K = FRACTURE GRADIENT - FLUID PRESSURE GRADIENT / OVERBURDEN GRADIENT - FLUID PRESSURE GRADIENT
OVERBURDEN WAS HELD CONSTANT AT 19.2
FRACTURE GRADIENT (LB/GAL)
DEPTH - 1000'
20
19
18
17
16
15
14
13
12
11
10
9
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20

EXHIBIT IX

GEOLOGICAL CROSS SECTION
EXAMPLE OF NATURALLY OCCURRING
INCREASE IN PRESSURE GRADIENT
WITH DECREASE IN DEPTH



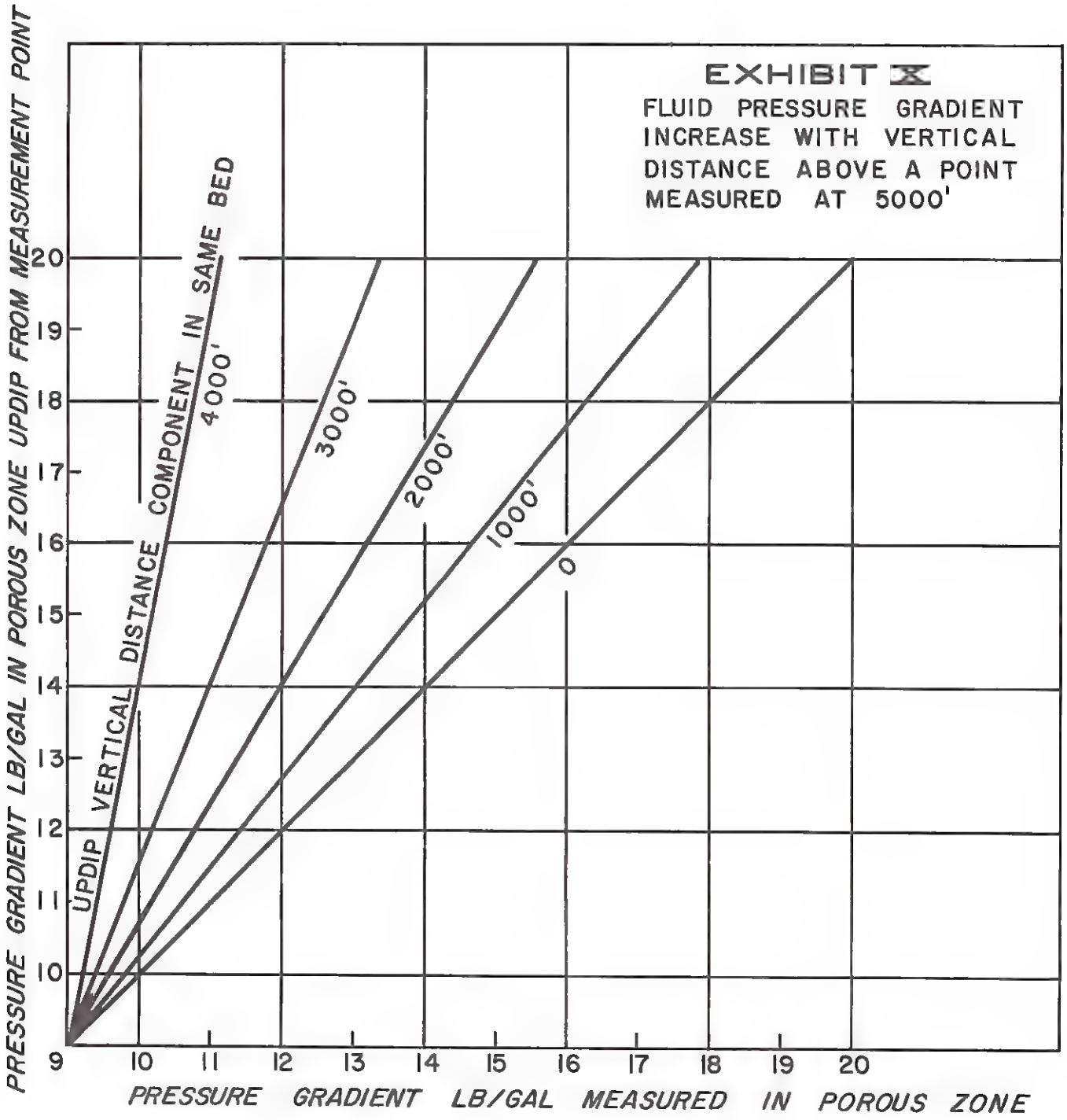


EXHIBIT X
FLUID PRESSURE GRADIENT INCREASE WITH VERTICAL DISTANCE ABOVE A POINT MEASURED AT 5000'
PRESSURE GRADIENT LB/GAL IN POROUS ZONE UPDIP FROM MEASUREMENT POINT
PRESSURE GRADIENT LB/GAL MEASURED IN POROUS ZONE
UPDIP VERTICAL DISTANCE COMPONENT IN SAME BED
4000'
3000'
2000'
1000'
0
9
10
11
12
13
14
15
16
17
18
19
20

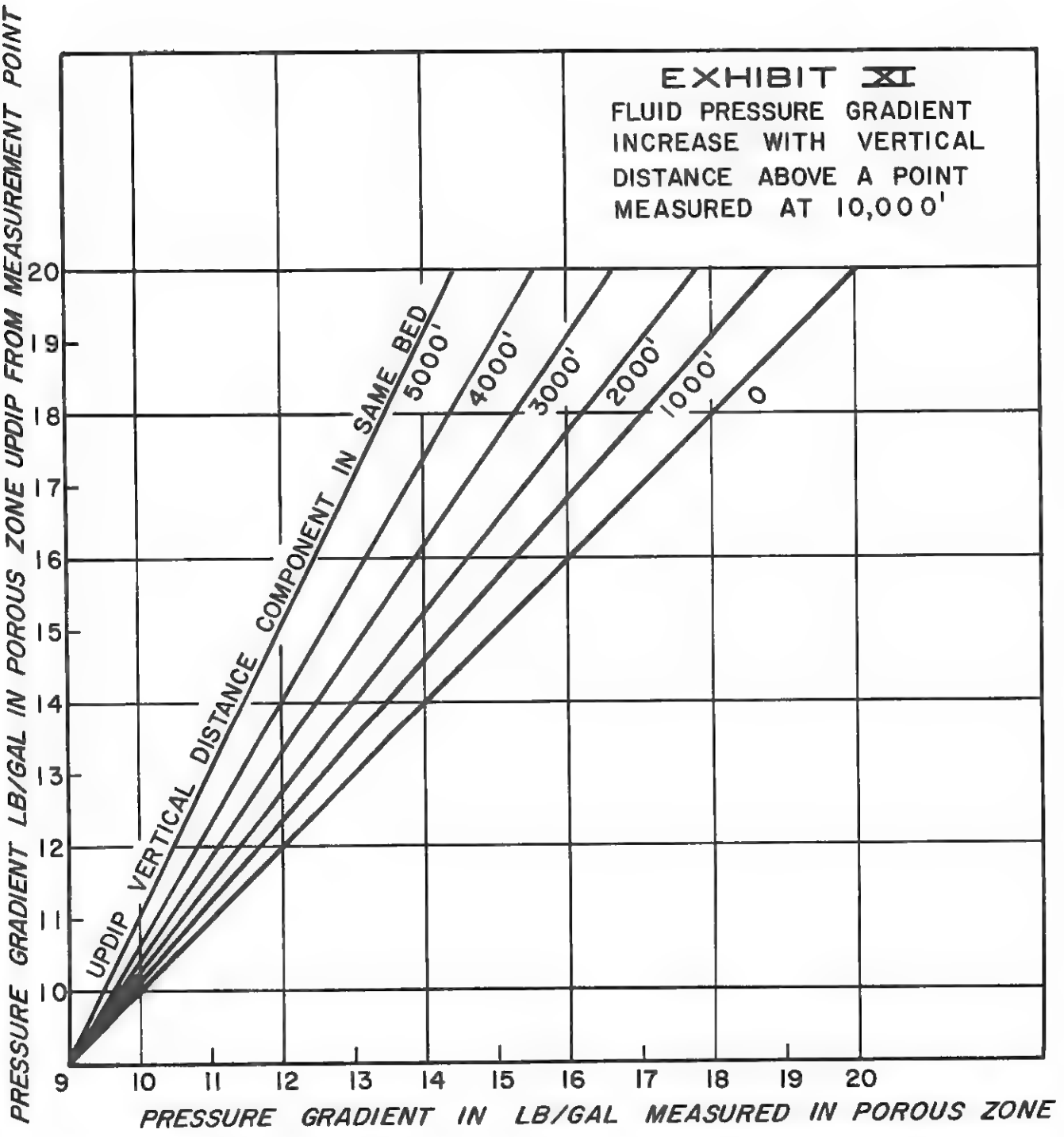


EXHIBIT XI
FLUID PRESSURE GRADIENT INCREASE WITH VERTICAL DISTANCE ABOVE A POINT MEASURED AT 10,000'
UPDIP VERTICAL DISTANCE COMPONENT IN SAME BED
5000'
4000'
3000'
2000'
1000'
0
PRESSURE GRADIENT LB/GAL IN POROUS ZONE UPDIP FROM MEASUREMENT POINT
PRESSURE GRADIENT IN LB/GAL MEASURED IN POROUS ZONE
9
10
11
12
13
14
15
16
17
18
19
20

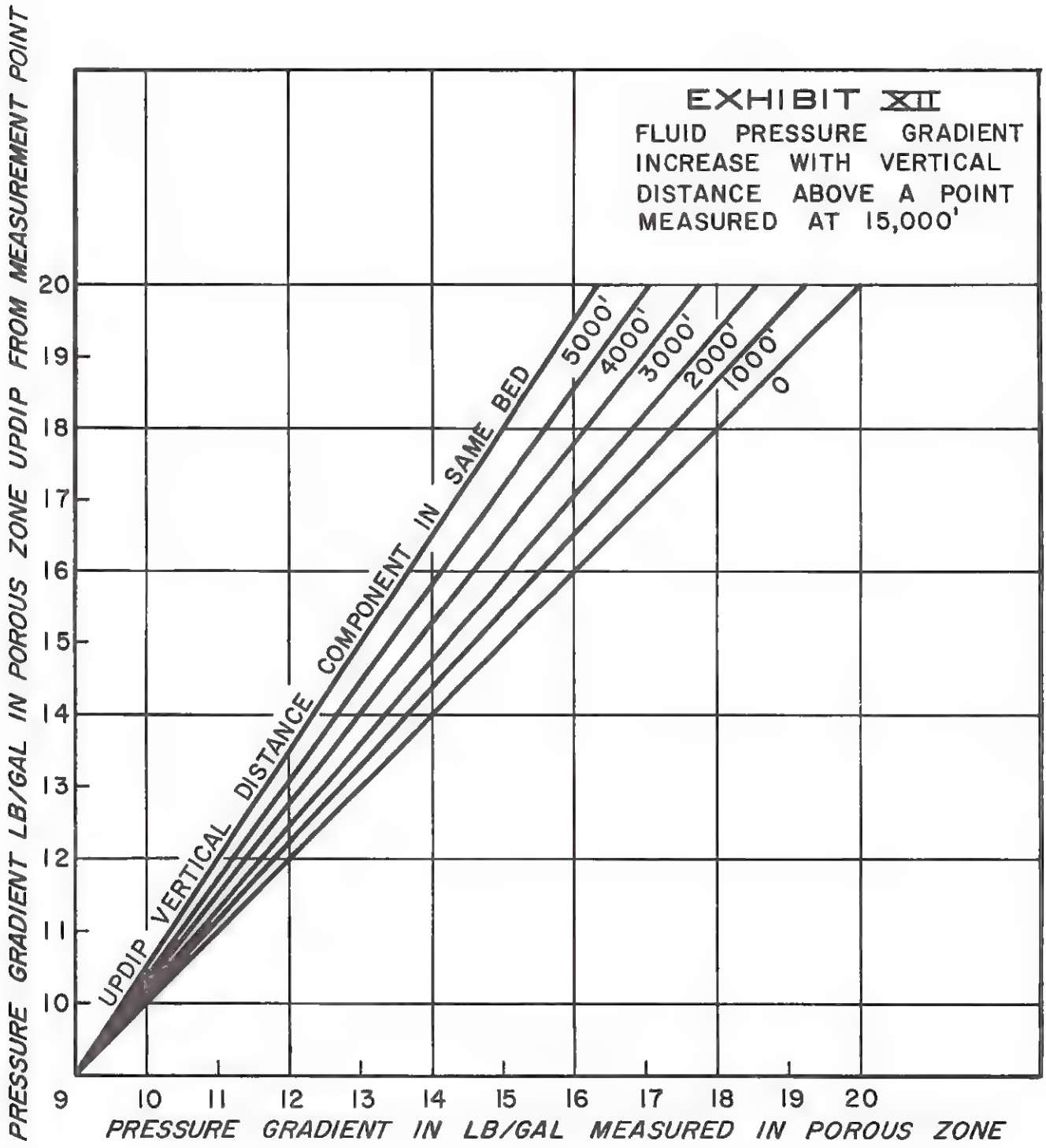


EXHIBIT XII
FLUID PRESSURE GRADIENT INCREASE WITH VERTICAL DISTANCE ABOVE A POINT MEASURED AT 15,000'
UPDIP VERTICAL DISTANCE COMPONENT IN SAME BED
5000'
4000'
3000'
2000'
1000'
0
PRESSURE GRADIENT LB/GAL IN POROUS ZONE UPDIP FROM MEASUREMENT POINT
PRESSURE GRADIENT IN LB/GAL MEASURED IN POROUS ZONE
9
10
11
12
13
14
15
16
17
18
19
20

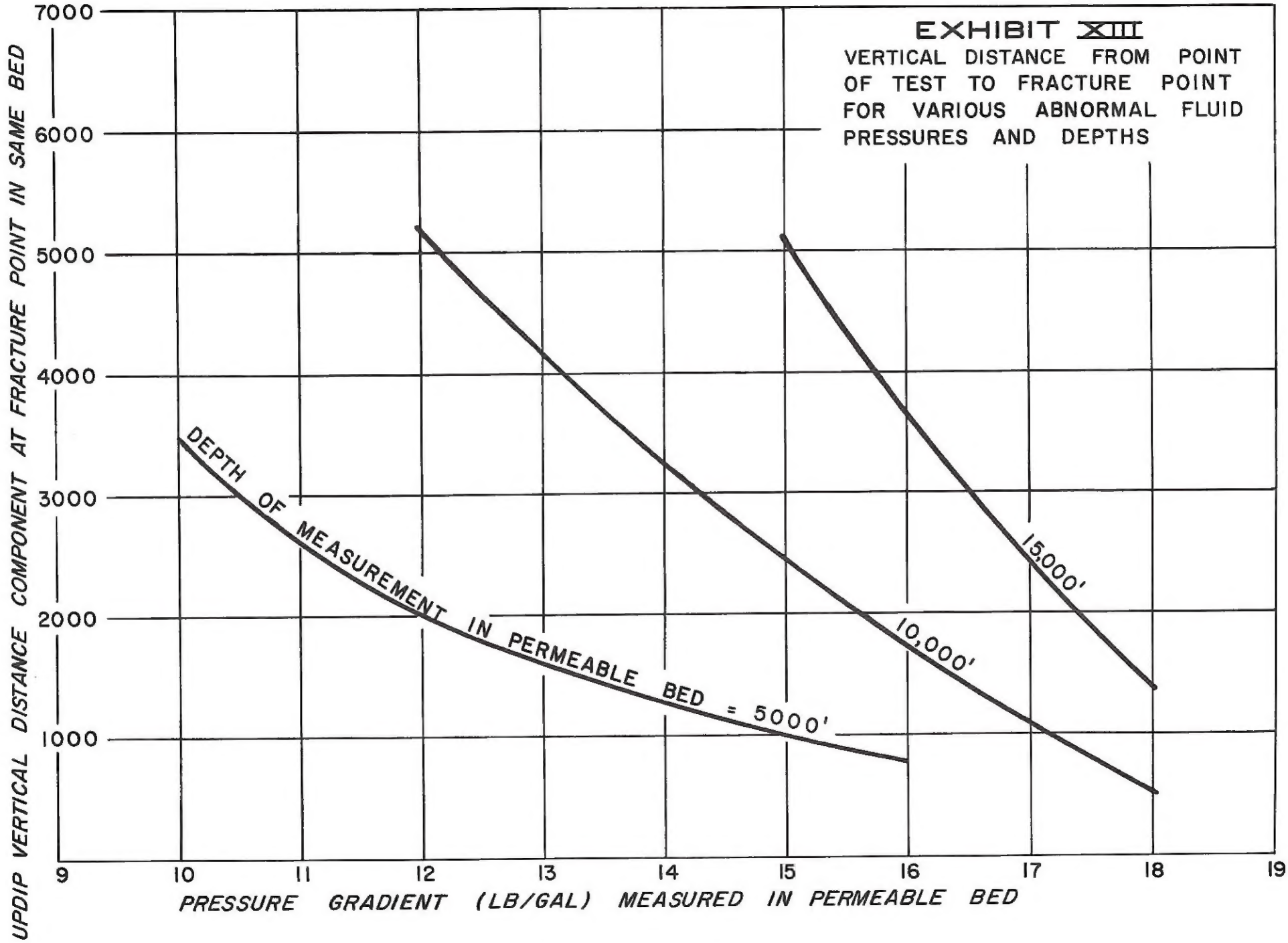


EXHIBIT XIII
VERTICAL DISTANCE FROM POINT OF TEST TO FRACTURE POINT FOR VARIOUS ABNORMAL FLUID PRESSURES AND DEPTHS
UPDIP VERTICAL DISTANCE COMPONENT AT FRACTURE POINT IN SAME BED
7000
6000
5000
4000
3000
2000
1000
DEPTH OF MEASUREMENT IN PERMEABLE BED = 5000'
10,000'
15,000'
9
10
11
12
13
14
15
16
17
18
19
PRESSURE GRADIENT (LB/GAL) MEASURED IN PERMEABLE BED

M

EXHIBIT XIV

FLUID PRESSURE GRADIENT
V S
FRACTURE GRADIENT
FOR ABNORMAL PRESSURE DATA
>10,000' DEPTH
>11 LB / GAL

PRESSURE GRADIENT LB. / GAL.
= −20.2 + 1.93 X FRACTURE GRADIENT LB/GAL
CORRELATION COEFFICIENT = .7449
STANDARD ERROR OF ESTIMATE = 1.27 LB/GAL

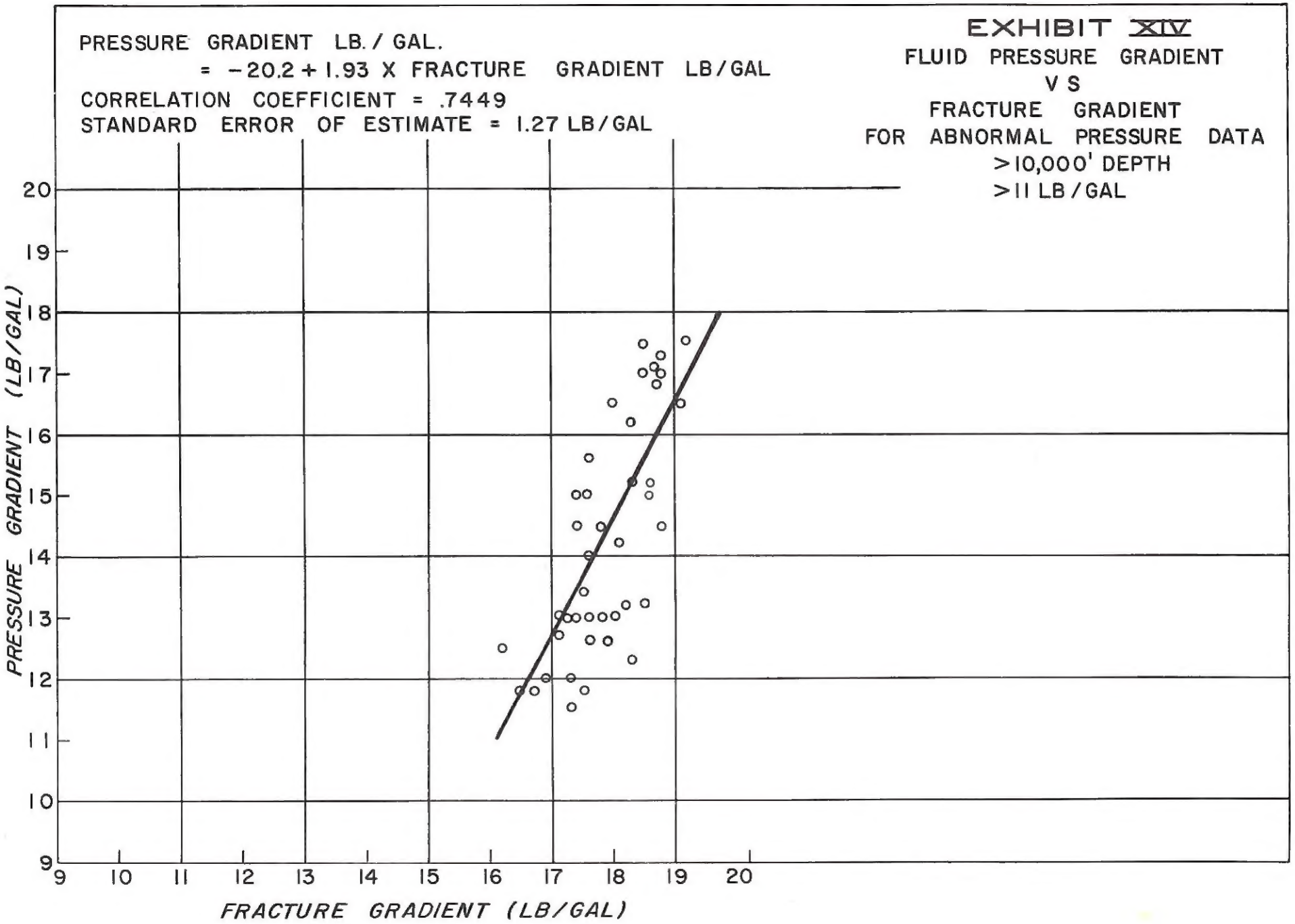
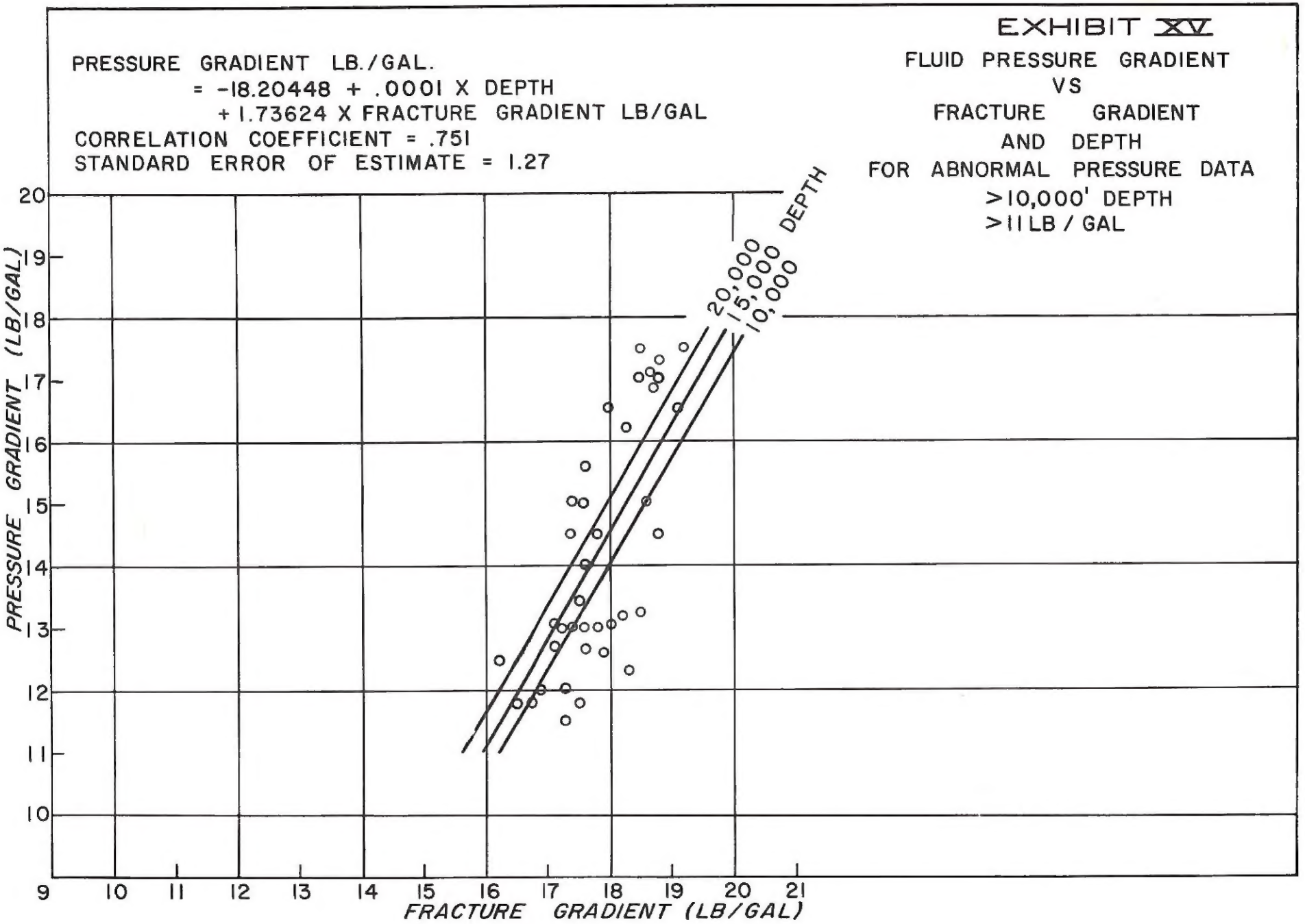


EXHIBIT XV

FLUID PRESSURE GRADIENT
VS
FRACTURE GRADIENT
AND DEPTH
FOR ABNORMAL PRESSURE DATA
>10,000' DEPTH
>11 LB / GAL

PRESSURE GRADIENT LB./GAL.
= -18.20448 + .0001 X DEPTH
+ 1.73624 X FRACTURE GRADIENT LB/GAL
CORRELATION COEFFICIENT = .751
STANDARD ERROR OF ESTIMATE = 1.27



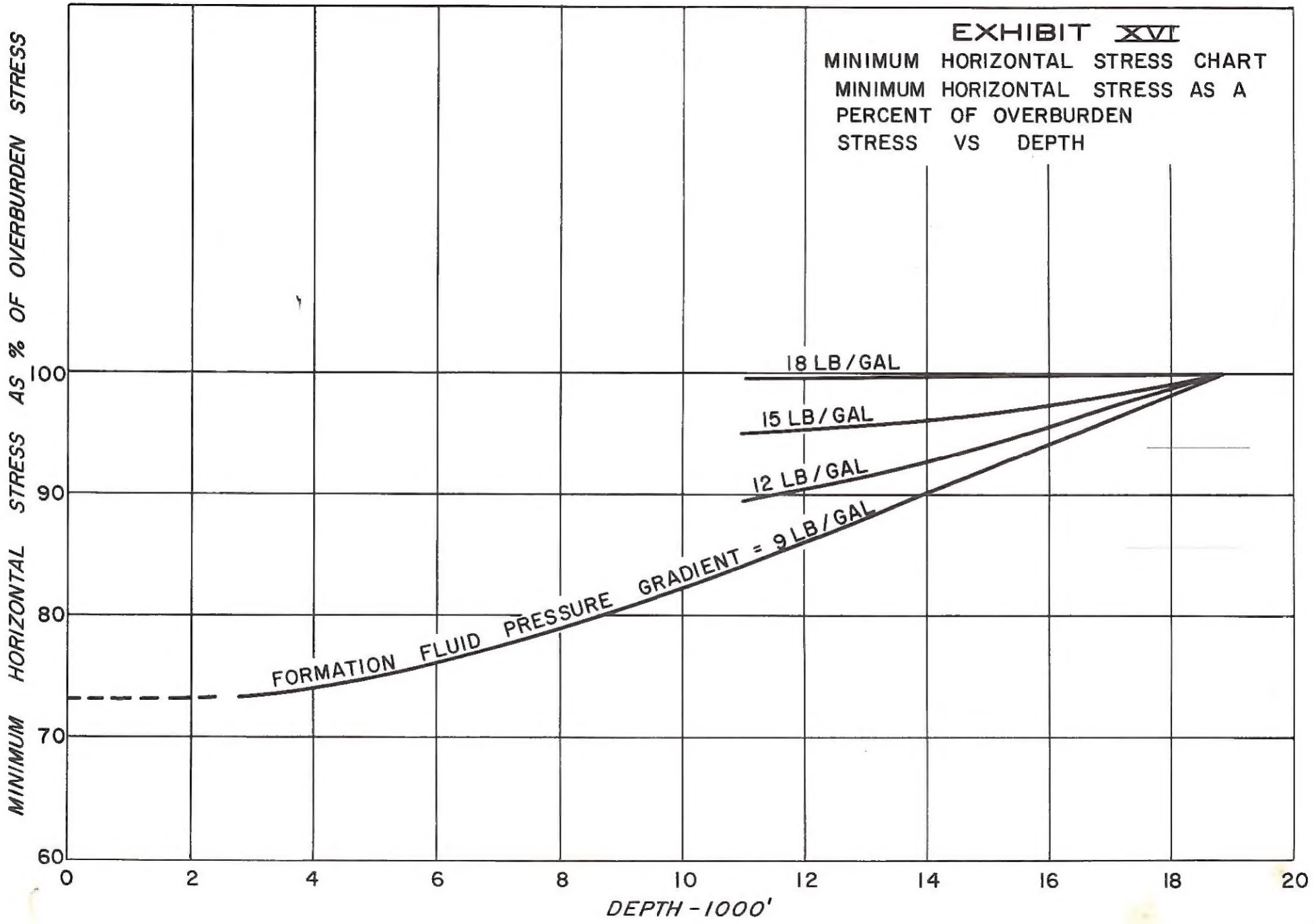


EXHIBIT XVI
MINIMUM HORIZONTAL STRESS CHART
MINIMUM HORIZONTAL STRESS AS A PERCENT OF OVERBURDEN STRESS VS DEPTH
MINIMUM HORIZONTAL STRESS AS % OF OVERBURDEN STRESS
100
90
80
70
60
0
2
4
6
8
10
12
14
16
18
20
DEPTH - 1000'
18 LB/GAL
15 LB/GAL
12 LB/GAL
FORMATION FLUID PRESSURE GRADIENT = 9 LB/GAL